NON-PUBLIC?: N

ACCESSION #: 9001110176

LICENSEE EVENT REPORT (LER)

FACILITY NAME: River Bend Station PAGE: 1 OF 5

DOCKET NUMBER: 05000458

TITLE: Reactor Scram Due to a Fault on an Offsite Transmission Line

EVENT DATE: 12/01/89 LER #: 89-042- REPORT DATE: 01/02/90

OTHER FACILITIES INVOLVED: DOCKET NO: 05000

OPERATING MODE: 1 POWER LEVEL: 097

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR SECTION:

50.73(a)(2)(iv)

LICENSEE CONTACT FOR THIS LER:

NAME: L. A. England - Director, Nuclear TELEPHONE: (504) 381-4145

Licensing

COMPONENT FAILURE DESCRIPTION:

CAUSE: X SYSTEM: EA COMPONENT: 59 MANUFACTURER: W120

REPORTABLE NPRDS: Y

SUPPLEMENTAL REPORT EXPECTED:

ABSTRACT:

At 0628 on 12/1/89 with the unit at 97 percent power (Operational

Condition 1), the main turbine generator tripped, resulting in a reactor

scram. The generator tripped due to the main generator protection

breakers tripping as a result of sensing a fault on an offsite 230KV

line. The fault failed to clear at the 230KV switchyard due to a failed relay and slow breaker response time following the signal from a backup relay.

Immediately following the generator trip, the station 4.16KV normal switchgear (1NNS-SWG1A) failed to successfully transfer to offsite power. This caused an undervoltage condition which initiated an automatic start of the Division III high pressure core spray (HPCS) emergency diesel generator. Initiation of the Division III standby service water pump 1SWP*P2C also occurred due to a momentary loss of power to the initiating trip units. The Division III emergency diesel generator restored power to the bus per design.

The reactor scram placed the unit in the safe shutdown condition. Since all safety systems functioned as designed, there was no impact on the safe operation of the plant or to the health and safety of the public as a result of this event.

END OF ABSTRACT

REPORTED CONDITION

At 0628 on 12/1/89 with the unit at 97 percent power (Operational Condition 1), the main turbine generator (*TG*) tripped, resulting in a reactor scram. The generator tripped due to the main generator protection breakers tripping as a result of sensing a fault on an offsite 230KV line. The fault failed to clear at the 230KV switchyard due to a

failed relay (*RLY*) and slow breaker response time following the signal from a backup relay.

Immediately following the generator trip, the station 4.16KV normal switchgear (1NNS-SWG1A) (*SWGR*) failed to successfully transfer to offsite power. This caused an undervoltage condition which initiated an automatic start of the Division III high pressure core spray (HPCS) emergency diesel generator (*DG*). Initiation of standby service water pump 1SWP*P2C also occurred due to a momentary loss of power to the Division III initiating trip units. The Division III emergency diesel generator (DG) restored power to the bus per design. Since this event resulted in the actuation of engineered safety features (ESFs) it is hereby reported under 10CFR50.73 (a) (2) (iv).

INVESTIGATION

The investigation that followed the event revealed that the turbine trip was caused by a severed static line on an offsite 230 KV transmission line which caused a phase to ground fault. The fault did not immediately clear due to a failed relay and a slow 230 KV circuit breaker clearing time at the offsite 230 KV switchyard (Fancy Point Substation). The slow fault clearing time was sufficient for the 64M relay protecting the main generator to operate and trip circuit breakers 20635 and 20640 at the offsite switchyard isolating the generator from the fault. The initial evaluation for the static line failure indicates a potentially deficient pole ground connection to the static line.

The investigation revealed that the Zone 1 directional distance ground relay 21GS1 (Westinghouse type SDG relay) failed to operate properly. Per design, the Zone 2 (a backup to the Zone 1 relay) directional distance ground relay (21GS2) operated after a 20 cycle delay and simultaneously sent a trip signal to breaker 20745 and initiated a breaker failure timing sequence. The breaker failure relay, was energized because breaker 20745 failed to operate within the expected time period upon receiving a trip signal from the Zone 2 directional ground relay. The time from the fault initiation to the trip from the breaker failure backup relay actuation was approximately 31 cycles. This was sufficient time for the 64M (*64*) relay for main generator protection to operate and trip breakers 20640 and 20635 to isolate the unit from the fault. The SDG relay failure was traced to a failed component in a circuit that is only active when the relay is used in a Zone 1 protection application. All remaining SDG relays at the

offsite 230 KV switchyard in a Zone 1 application have been tested for the failure mode and were found to be functioning properly.

Immediately following the generator trip, the station 4.16KV normal switchgear (1NNS-SWG1A & 1NNS-SWG1B) did not fast transfer to an offsite power source. This was per design because the voltage was below the transfer permissive value at that time. Switchgear 1NNS-SWG1B was able to complete a successful slow transfer however, 1NNS-SWG1A did not. The

transfer schemes for 1NNS-SWG1A&B rely on sufficient
voltage levels on
the secondary of the station preferred transformers (1RTX-XSR1D and
1RTX-XSR1C). When the fault occurred, voltage on the secondary of
station preferred transformers 1RTX-XSR1C and 1RTX-XSR1D was depressed to
3504 V and per design the 59R (*59*) relays (undervoltage/overvoltage) on
1NNS-SWG1A & 1NNS-SWG1B dropped out. At that time, the auxiliary relays
(59RX) operated and removed the permissive for transfer. When the fault
cleared, the 59R relay for 1NNS-SWG1B energized, resetting the 59RX relay
for that switchgear thus allowing a slow transfer of 1NNS-SWG1B.
Switchgear 1NNS-SWG1A did not slow transfer as expected but did manage to
complete the transfer in approximately six (6) minutes. Testing of the
59R relay (Westinghouse KV-1) for 1NNS-SWG1A revealed that it had failed.
Due to the failure of the non-safety related 4.16KV switchgear 1NNS-SWG1A
to transfer (fast and slow) from normal station service transformer
1STX-XNS1C to preferred station service transformer 1RTX-XSR1C, a loss of
power to the high pressure core spray (HPCS) safety-related 4.16KV bus
1E22*S004 and the non-safety related 4.16KV bus 1NNS-SWG1C occurred. As
a result of the loss of power to the 1E22*S004 bus, the HPCS DG received
an automatic initiation signal due to the bus undervoltage condition.
The HPCS D/G successfully started and its output breaker automatically
closed restoring voltage to the bus per design.
The initiation of standby service water pump, 1SWP*P2C, resulted from a

loss of power to the initiating trip units which actuate on low normal service water pressure. The trip units are supplied by a 120VAC/24VDC power supply which is powered from the HPCS 480VAC bus (1E22*S002). Power was restored to the Division III bus via the Division III emergency diesel generator. Upon restoring power to the Division III bus, the trip signal from trip units 1SWP*ES21/J,K,L and M sealed in via relay 1SWPN18-63. The initiation of 1SWP*P2C occurred following the timing out of relay 1SWPC08-62-A.

Immediately following the scram, recirculation pump breakers 3A, 4A, 3B and 4B (normal feed) tripped on an end of cycle-recirc pump trip (EOC-RPT) signal followed by the tripping of recirculation pump breakers 5A and 5B due to electrical interlocks. As a result of receiving a turbine trip at 97 percent power, the reactor vessel experienced a pressure transient. The highest pressure recorded by the emergency response information system (ERIS) was 1126.8 PSI. Due

to reaching the ATWS setpoint of 1127 PSI (minus the design tolerance) ARI and ATWS/RPT initiated. The ARI signal sealed in per design and the ATWS/RPT immediately cleared per design due to pressure being reduced below the trip setpoint. The pressure reduction was a normal design function of 9 relief valves opening (5 low-low set function and 4 additional safety relief valves (SRVs)). Following the ARI/ATWS initiation, the recirculation pump low speed RPM permissive was met and

recirculation pump breakers 2A & 2B closed from the initial EOC-RPT signal, placing the pumps on low speed.

Similar events have been reported in LERs 85-063, 86-021, and 86-055.

The failure of the static line was an external factor that played a role in initiating this event. One of the similar events listed above also involved an external factor, a lightning strike as reported in LER 85-063. The remaining two events are similar due to their sequential nature. In both events a transformer fault progressively led to a reactor scram. A brief description of each event is provided below.

. LER 85-063: GSU reported a reactor scram due to a main turbine generator trip on a false main turbine generator power-load imbalance caused by a failed pressure transducer coupled with a lightning strike on a 500 KV transmission line.

. LER 86-021: GSU reported an event in which a transformer fault led to a voltage transient in a 13.8 KV switchgear which resulted in a reactor scram and a HPCS injection.

. LER 86-055: GSU reported an event in which a faulted transformer caused a loss of power to the reactor protection system (RPS) A bus concurrent with a failure in the RPS B train backup scram circuitry which resulted in a reactor scram.

CORRECTIVE ACTION

The offsite static line which initiated this event is undergoing repairs. The failed relay in the offsite 230 KV switchyard was replaced and the

replacement has been successfully tested. Although the failure of the Westinghouse SDG relay has been determined to be an isolated. failure, GSU is revising system maintenance procedures to include a test of the failed portion of the SDG relay circuitry.

The failure of the offsite breaker 20745 to operate immediately upon receipt of the signal from the Zone 2 relay has been evaluated. Subsequent testing and inspections (internal and external) have revealed no reason for this breaker to function improperly since it passed all of the testing and inspection requirements. Therefore, the circuit breaker has been approved to be returned to service.

The failed relay (59R) which prevented the station normal switchgear from completing a slow transfer was replaced. GSU has initiated a modification (modification request (MR) 89-241) to replace the Westinghouse KV-1 relay with an ITE 59H relay in the 59R application. All other station applications of this type of relay were evaluated with none identified in safety related systems. In addition, busses 1NNS-SWG1A and 1NNS-SWG1B are currently being served from preferred station service transformers 1RTX-XSR1C and 1RTX-XSR1D, respectively.

SAFETY ASSESSMENT

There was no impact on the safe operation of the plant or to the health and safety of the public as a result of this event since the reactor scram placed the unit in the safe shutdown condition and all safety

systems functioned as designed.

NOTE: Energy Industry Identification System Codes are identified in the

text as (*XX*).

ATTACHMENT 1 TO 9001110176 PAGE 1 OF 1

GULF STATES UTILITIES COMPANY

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U.S. Nuclear Regulatory Commission

Document Control Desk

Washington, D.C. 20555

Gentlemen:

River Bend Station - Unit 1

Docket No. 50-458

Please find enclosed Licensee Event Report No. 89-042 for River Bend

Station - Unit 1. This report is being submitted pursuant to 10CFR50.73.

Sincerely,

J. E. Booker

Manager-River Bend Oversight

River Bend Nuclear Group

JEB/TFP/RGW/DCH/DEH/JCH/JFM/pg

cc: U.S. Nuclear Regulatory Commission

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